Diversification • Stability • Growth

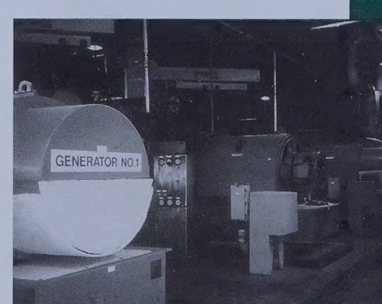
Annual Report 2002

ALGONQUIN POWER
Income Fund

Index

Algonquin Power Income Fund owns a diverse portfolio of operating interests in 47 hydroelectric, two biomass, one waste and two natural gas-fired cogeneration plants as well as a portfolio of passive fixed-income and preferred/dividend equity investment interests in five additional biomass and natural gas cogeneration plants in the United States and Canada.

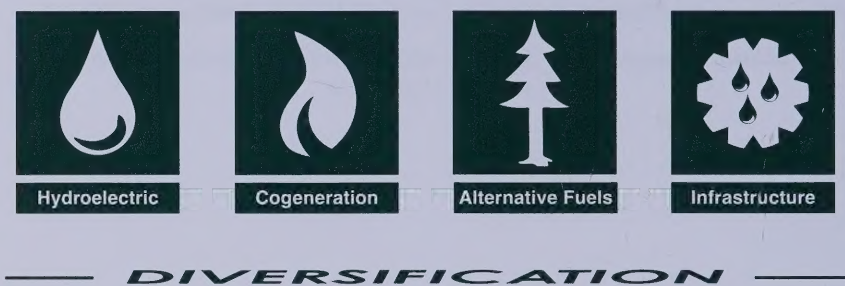
In addition, Algonquin owns five water reclamation and distribution facilities in the southern United States.



Algonquin Power Income Fund distributed $0.92 per trust unit during 2002, consistent with the previous year.

The Fund's stated diversification strategy was instrumental in offsetting weak hydrologic conditions that adversely affected hydroelectric revenues and net earnings. Drought and drought-like conditions continued during 2002 in several geographic regions where the Fund owns facilities. The diversification strategy, conceived and researched in 2000, was launched aggressively in 2001. It contributed significantly to mitigating the impact of hydrologic conditions in 2002 compared to 2001.

The diversification strategy unfolded throughout the year and established a solid balance between hydroelectric, cogeneration and alternative fuels. The Fund also continued to build its portfolio of infrastructure assets.



Balancing risk The Fund improved overall revenues, earnings and earnings per share during the year. Revenues increased by 111% to $94.8 million; net earnings increased 135% to $16.2 million. The Fund also increased cash available for distribution to $44.7 million or $0.77 per trust unit.

Historically, the most significant risk capable of impacting Fund performance has been widespread hydrologic conditions that can adversely affect the "run-of-the-river" hydroelectric generating assets.

The Fund's Manager has undertaken a variety of pre-emptive strategies to mitigate the potential impact of hydrology including:

- Strategically acquiring hydroelectric generating assets across diverse geographic regions to balance risk of hydrology in any one area;
- Investing in existing hydroelectric assets to improve performance and positioning the assets to take full advantage of their low operating cost structure; strengthening technical and management capability;
- Acquiring hydroelectric generating assets in diverse regulatory jurisdictions; and
- Planning reserves to support distributions as necessary given the unpredictable nature of not just weak hydrology, but more important, the unpredictable length of time the conditions could persist.

These strategic actions have allowed management to insert more certainty into hydroelectric operations that, by nature, function in an uncertain climatic environment. Notwithstanding these efforts, as a direct result of lower than average water flows, energy production in 2002 from the Fund's hydroelectric facilities was approximately 82% of long-term averages, consistent with 2001.

Although the Fund believes that the conditions affecting its hydroelectric facilities are temporary and that long-term average energy projections continue to be valid, the Fund accelerated its asset diversification into other forms of power generation technologies and infrastructure to mitigate the volatility experienced by the hydroelectric facilities.

Diversification in detail The Fund repositioned its power-generation portfolio by the end of the year. The overall portfolio now has a stronger balance between hydroelectric (48%), natural gas cogeneration (34%) and alternative fuels or biomass-fired generating assets (18%). The size of the Fund's infrastructure portfolio has also been increased. After completion of transactions announced at the beginning of 2003, the Fund is in a good position to provide stable, predictable and increased cash distributions to unitholders.

Strategic investments in the Fund's diversification and acquisition strategies during 2002 included:

- Completion of the acquisition of KMS Power Income Fund by an exchange of units, adding to both the alternative fuels (biomass) and cogeneration portfolios;
- Acquisition of a 43.5 megawatt facility in Sanger, California building the Fund's cogeneration portfolio;
- Acquisition of Bella Vista Water Company, Inc. in Arizona and the Tall Timbers and Woodmark water reclamation facilities in Texas to build infrastructure assets;
- The Fund completed a unit offering of $98.5 million during the fourth quarter to complete these transactions; and
- In early 2003, the Fund accelerated and solidified the diversification strategy by acquiring Litchfield Park Service Company, a water reclamation and distribution company in Arizona; a 56 megawatt cogeneration facility in Windsor Locks, Connecticut and entered into an agreement to acquire a partnership interest in an 80 megawatt alternative fuels (biomass) facility in Virginia. The Fund also announced that it has entered into agreements to reduce the rates on its power purchase contracts for its New Hampshire hydroelectric facilities to market rates. The Fund will receive approximately $30.6 million (U.S. $20.4 million) in cash as a result of the renegotiation.

The Fund also completed changes to its contractual arrangements with the Manager. The Manager will be paid on a cost-reimbursement basis only and receive incentive fees based on 25% of distributable cash in excess of $0.92 per trust unit per annum. This contractual change ties management incentives directly to increases in cash distributions to unitholders.

The Fund also announced a switch to a monthly distribution policy in October, 2002 to reflect changes requested by the unitholders.

In addition, the Fund maintained its Standard & Poor's SR-2 Very High stability rating and in the second quarter of 2002 received an A- bank credit rating.

Outlook – Stability & Growth The Fund remains committed to improving the stability of distributions to unitholders by improving the performance of existing assets plus the acquisition of assets to provide stable cash flows. We will continue our growth strategy by taking advantage of new, complementary diversification opportunities to provide stable income flow and balance risk.

The Manager is studying opportunities to capitalize on the highly predictable cash flows, regulated markets and perpetual geographic monopoly positions of its growing infrastructure investments. These investments are primarily located in high growth residential areas in the southern U.S.

The success of your Fund is primarily due to the support and confidence of unitholders as well as continuing successful access to capital through the capital markets and our established banking credit facilities. We look forward to maintaining stable cash flows and growing our portfolio in 2003.

On behalf of the Trustees and the Manager, thank you for your continued support.

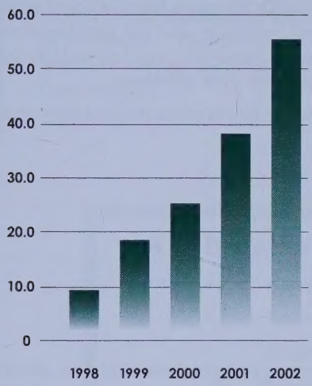
K. Moore

Ken Moore
Chairman

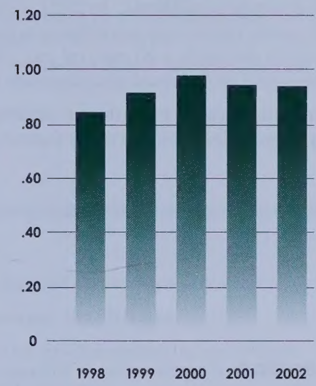
(THOUSANDS OF CANADIAN DOLLARS EXCEPT AS NOTED.)

YEARS ENDED DECEMBER 31	2002	2001	2000	1999	1998
Statement of operations data					
Energy Sales					
Hydroelectric	$ 40,681	$ 36,270	$ 43,996	$ 13,709	$ 4,711
Cogeneration	23,566	-	-	-	-
Alternative fuels	4,994	1,020	-	-	-
Total energy sales	$ 69,241	$ 37,290	$ 43,996	$ 13,709	$ 4,711
Waste disposal sales	10,697	-	-	-	-
Water reclamation/distribution	7,974	2,522	-	-	-
Interest and dividend income	6,851	5,157	2,697	5,896	3,601
Total revenue	$ 94,763	$ 44,969	$ 46,693	$ 19,605	$ 8,312
Operating Profit					
Hydroelectric	$ 26,985	$ 24,835	$ 33,351	$ 13,015	$ 5,269
Cogeneration	15,069	1,166	-	-	-
Alternative fuels	7,292	719	-	-	-
Infrastructure	4,678	1,199	-	-	-
Other	851	2,530	1,063	2,016	1,225
Total operating profit	$ 54,875	$ 30,449	$ 34,414	$ 15,301	$ 6,494
Earnings before interest expense, loan payment fee and income from note prepayment	26,726	18,662	23,937	8,732	3,745
Net earnings	16,150	6,864	13,364	7,209	3,195
Net earnings per trust unit	0.28	0.17	0.54	0.37	0.29
Distributions to unitholders	55,192	37,302	24,755	18,467	9,281
Distribution to unitholders per trust unit	0.92	0.92	0.97	0.90	0.835
Cash available for distribution	44,742	28,813	19,325	13,779	8,192
Cash available for distribution per trust unit	0.77	0.73	0.78	0.70	0.75
Balance Sheet Data					
Cash and cash equivalents	$ 24,838	$ 31,713	$ 9,580	$ 9,602	$ 2,124
Working capital	15,376	19,011	2,024	(768)	(2,044)
Capital and intangible assets, and long term investments	674,495	467,312	310,056	305,084	130,124
Total assets	723,038	512,384	328,502	325,988	135,096
Long-term liabilities and revolving line of credit	86,099	50,665	73,244	83,985	4,758
Unitholders' equity	537,771	411,613	219,559	205,221	123,944
Number of units outstanding As at December 31	67,887,612	50,875,772	27,020,472	24,020,472	14,090,472

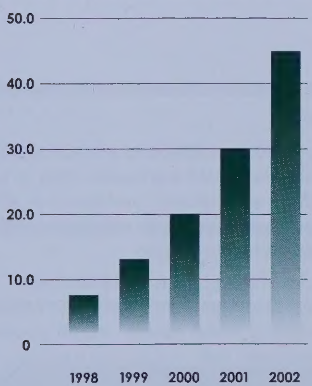
Annual distributions ($ millions)



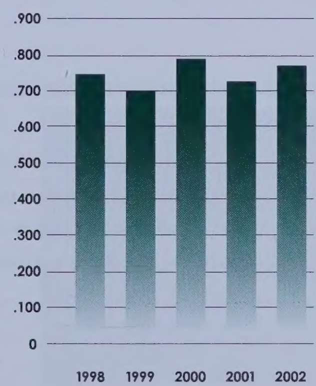
Distributions to unitholders ($/trust unit)



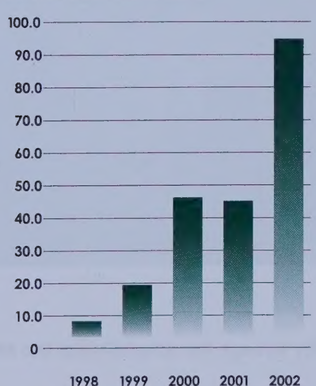
Cash available for distribution ($ millions)



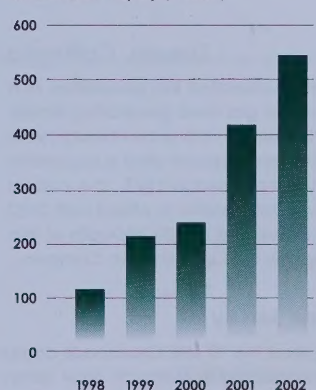
Cash available for distribution ($/trust unit)



Annual revenues ($ millions)



Unitholders' equity ($ millions)



Algonquin Power Income Fund's diversification strategy, initiated in 2001, was launched to mitigate the risk of fluctuations that can result from natural hydrologic conditions. In 2002, when much of North America was inflicted with drought or near-drought conditions, these weak hydrologic conditions adversely affected revenues and net earnings from hydroelectric operations. The Fund's strategy to diversify into natural gas cogeneration and alternative fuels as well as infrastructure assets helped offset this situation and maintained distributions consistent with the year previous.

Investment in other power generation assets provides an additional opportunity to enhance the stability and sustainability of cash flows to unitholders and provides a platform for future growth.

Cogeneration Cogeneration is the use of primary energy to produce heat and electricity. It is based on the recovery and use of waste heat produced during the generation of electricity. Often, natural gas is used to produce both electricity and steam. The steam produced is normally required by an associated or nearby commercial facility and the electricity is sold to a utility or is used within the commercial facility. Food processing, pulp and paper and chemical plants are common users of cogeneration technology.

Benefits

- Predictable generation with no natural fluctuations
- Low technology risk using proven turbine engines
- Operating risk can be minimized from power purchase agreements matched with gas supply
- Revenues based on long-term agreements

Sanger, California

During 2002, the Fund completed the acquisition of a 43.5 megawatt, natural gas-fired generating facility located in Sanger, California. It is a combined cycle generating station and has demonstrated a successful operating history since it opened in 1991. The current power purchase agreement remains in effect until 2022 and calls for the delivery of 38,000 kilowatts of firm capacity to Pacific Gas and Electric Company.

Crossroads, New Jersey

The Fund also acquired the 10 MW Crossroads cogeneration facility through the acquisition of the KMS Power Income Fund. It is a located in Mahwah, New Jersey.

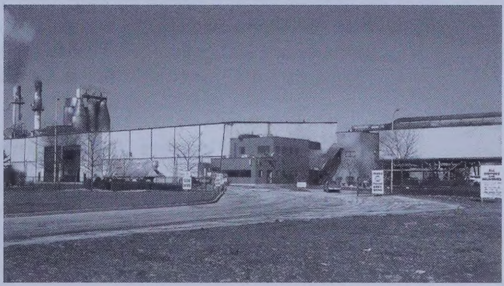
Alternative Fuels Biomass is one type of alternative fuel source. It is organic matter that is burned in an incinerator and converted into steam or combustible gas for greater efficiency and cleaner performance. The steam or combustible gas is used to drive a turbine generator to produce electricity. Biomass sources include food processing, agricultural and forestry by-products as well as gas emitted from landfill.

Benefits

- Non-fossil fuels burned to produce electricity
- Sourced from biomass, landfill gas
- Highly efficient and environmentally acceptable
- Supply or pay fuel contracts

Peel Ontario

Completion of the acquisition of KMS Power Income Fund in 2002 added the KMS Peel waste-to-energy facility in Brampton, Ontario. The facility processes 500 tonnes daily and produces a maximum of 10 megawatts of electrical energy.



The Peel plant is designed to incinerate non-recyclable materials including municipal solid waste to produce steam. Steam drives a turbine generator to produce electricity. Five integrated operating systems are in place at this state-of-the-art operation.

Peel is designed to operate 24 hours a day, 365 days a year. The facility has entered into a long-term waste supply agreement with the regional municipality that includes the City of Brampton, Ontario. The electrical energy produced by Peel is sold to the provincial utility under a long-term power purchase agreement.

Joliet, Illinois

The Fund also acquired 1.6 MW the Joliet biogas facility through the acquisition of the KMS Power Income Fund.

Infrastructure Infrastructure assets such as water reclamation and distribution facilities offer highly-predictable cash flows from a captive user base of customers within a regulated utility.

Benefits

- Highly predictable cash flows with strong growth record
- Regulated utility provides return protection
- Perpetual geographic monopoly

Bella Vista Water Company

The Fund completed the acquisition of the Bella Vista Water Company in 2002. The company distributes water to approximately 7,000 commercial/light industrial and residential customers in Cochise County, Arizona.

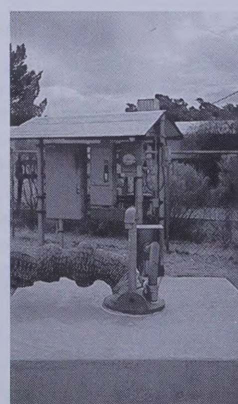
All of the potable water supplied by Bella Vista is from groundwater. Twenty-nine wells with a total production capability of 5,800 gallons per minute serve four communities in the County.

Tall Timbers Utility Company

Another acquisition was the Tall Timbers Utility Company in Tyler, Texas, near Dallas. Tall Timbers operates a water reclamation facility servicing more than 1,000 customers.

Woodmark Utility Company

Adjacent to Tall Timbers in Tyler, Texas, Woodmark also operates a water reclamation facility serving almost 800 customers.



Bella Vista Water Company

Woodmark Utility Company

Other Acquisitions Additional acquisition opportunities were initiated during 2002. Two accretive acquisitions were concluded in early 2003:

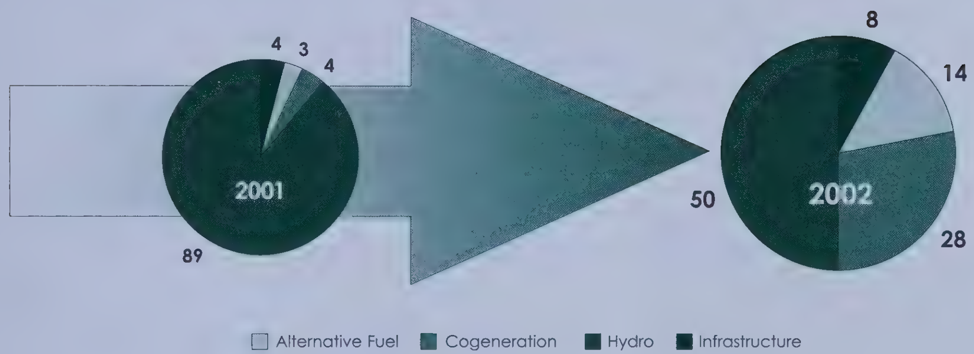
Litchfield Park Service Company

A water reclamation and distribution business in Arizona that serves a combined total of 18,000 connections. The company is located in the fastest growing county in the United States and is expected to add 4,000 new connections in each of 2003 and 2004.

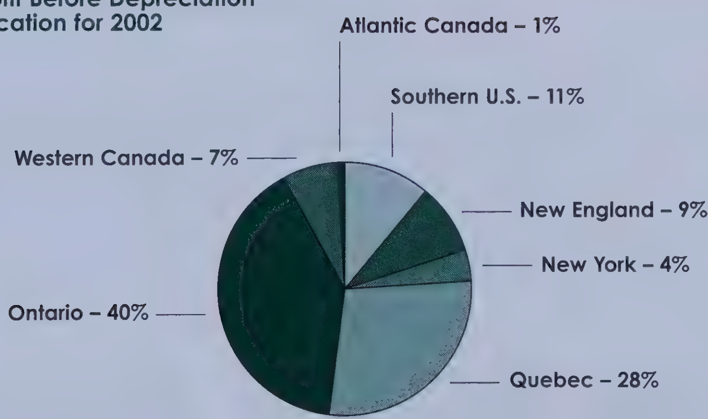
56 megawatt cogeneration facility in Windsor Locks, Connecticut

Delivers electricity to Connecticut Light and Power Company under a power purchase agreement and steam and electricity to the Ahlstrom Windsor Locks LLC paper products mill.

Operating Profit Before Depreciation by asset category



Operating Profit Before Depreciation by location for 2002



QUESTION

What are the results from the Fund's diversification strategy?

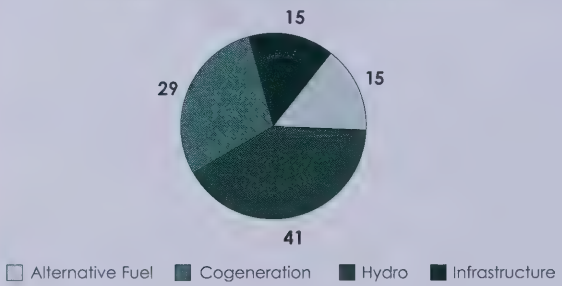
ANSWER

The Fund embarked on a diversification strategy during 2001. It was launched to balance the risks of weak hydrologic conditions that can adversely impact the Fund's "run-of-the-river" hydroelectric generating facilities and to provide long-term statistically predictable cash flows. Other renewable resource opportunities such as cogeneration, alternative fuels and infrastructure projects are not dependent on weather and tend to maintain a constant revenue flow to provide a strong balancing effect to hydroelectric generation.

Since the launch of the strategy last year, the Fund has acquired:

- *Six natural gas-fired cogeneration facilities or interests in facilities in the U.S. and Canada;*
- *Five alternative fuels (biomass) facilities or interests in facilities in the U.S. and Canada; and*
- *Six water reclamation or distribution facilities in the U.S.*

Expected Operating Profit before depreciation after completion of Litchfield Park and Windsor Locks transactions



These acquisitions have resulted in a re-positioning of the Fund's portfolio based on operating profit before depreciation from 100% hydroelectricity to 41%; cogeneration 29%; alternative fuels 15%; and 15% infrastructure to produce better balance against the risks of hydrologic conditions as well as predictable cash flows.

During 2002, when drought or near-drought conditions inflicted much of North America and adversely affected both revenues and earnings from hydroelectric operations, the diversification strategy was instrumental in producing more stable distributions for unitholders.

In addition, these diverse opportunities provide enhanced growth opportunities. Overall revenues, earnings and earnings per share were improved during 2002.

QUESTION

Will the diversification strategy continue?

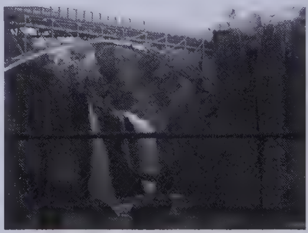
ANSWER

The Fund will continue to identify accretive acquisition opportunities to meet its goal of providing stability and growth for unitholders.

We will continue the diversification strategy by taking advantage of complementary opportunities to provide stable income flow and to balance risk.

Our goal is to achieve even more offsetting balance among our hydroelectric, cogeneration and alternative fuel sectors.

Ultimately, we will achieve diversification through the combination of technology, geography, regulatory environments and markets to reduce portfolio risk and provide sustainable, highly stable cash flows and returns to unitholders.



QUESTION

Explain plans for the Infrastructure Division.

ANSWER

Algonquin Power Income Fund holds infrastructure assets consisting of both water reclamation and distribution facilities.

The treatment of wastewater and distribution of potable water both offer highly predictable cash flows with strong growth potential.

Currently, the Fund owns six such operations in Arizona and Texas with a total of approximately 32,000 commercial or residential connections. During 2002, the Infrastructure Division provided eight per cent of Fund operating profit.

The Manager is studying opportunities to capitalize on the highly predictable cash flows, regulated markets and perpetual geographic monopoly positions of such investments. They are primarily located in high growth residential areas in the southern U.S.

QUESTION

What are the details of changes made in distribution policy?

ANSWER

The Fund switched to monthly rather than quarterly distributions beginning in October, 2002 to improve the internal rate of return for loyal unitholders.

This change in distribution policy, combined with the demonstrated success of the diversification strategy, work together to make your Fund a more appealing short and long-term investment.

QUESTION

Explain how contractual arrangements with the Manager have changed?

ANSWER

As announced at the last Annual General Meeting, compensation arrangements with the Manager have been amended to reflect the evolving governance and incentive fee arrangements in the income trust sector while accommodating unique aspects of the Fund's business and structure. The Trustees agreed with the Manager to the following changes effective January 1, 2002, except as noted:

- *Except for incentive fees, the Manager will be paid on a cost reimbursement basis only;*
- *Effective July 1, 2002 the Manager will be paid incentive fees based on 25% of the distributable cash flow in excess of $0.92 per trust unit per annum. There will be no further acquisition-based incentive fees paid to the Manager;*
- *Algonquin Power Systems Inc., which is owned by the same shareholders as the Manager and which operates most of the facilities directly or indirectly owned by the Fund, will be paid on a cost reimbursement basis only; and*
- *There will be no fees paid to the Manager as compensation for the Manager's consent to these amendments. However, the Trustees have agreed to extend the term of the management agreement for an additional five years with a rolling five years notice of termination.*

Algonquin Power Income Fund (the "Fund") is a publicly-traded Canadian income fund and an active consolidator of power generation and infrastructure facilities in Canada and the United States. Market capitalization has grown from $80 million in 1997 to approximately $600 million in 2002 as a result of the Fund's acquisition strategy. At December 31, 2002, the Fund had 67,887,612 units issued and outstanding and owned 62 generating and water reclamation and distribution facilities either directly or indirectly.

The Fund increased revenues to $94.8 million in 2002 from $45.0 million in 2001. Net income increased to $16.2 million in 2002 from $6.9 million in 2001. Earnings per trust unit increased to $0.28 in 2002 from $0.17 in 2001.

The Fund distributed $55.2 million to unitholders during 2002, an increase of $17.9 million from $37.3 million distributed during 2001. Distributions per unit remained constant at $0.92 during 2002 and 2001. During 2002, the Fund also increased its cash available for distribution to $44.7 million from $28.8 million in 2001. On a per unit basis, cash available for distribution increased approximately 5% to $0.77 for 2002, compared with $0.73 in 2001.

While the Fund was challenged by widespread below average water flows in 2002, the Fund believes that such conditions are temporary and long term average energy projections continue to be valid. Accordingly, the Fund believed it prudent to maintain current distribution levels in 2002. The Fund is confident that the portfolio is well structured to provide continuing value to unitholders through consistent distributions.

2002 Financial and Operating Highlights

Year ended December 31

All figures in thousands of dollars except as noted

	2002	2001
Revenues	94,743	44,969
Net Income	16,150	6,864
Distributions to unitholders	55,192	37,302
Per Unit		
Net income	**0.28**	0.17
Distributions to unitholders	**0.92**	0.92
Cash Available for Distribution	**44,742**	28,813
Cash available for distribution	**0.77**	0.773

The Fund's diversification strategy in 2002 continued to focus on the acquisition of non-hydroelectric, long-lived assets that have contributed to improved year-over-year results. While the Fund's hydroelectric generating facilities were impacted in 2002 by the below normal water flow conditions which have impacted hydroelectric generation in North America, the Fund realized the benefits of its diversified portfolio with increased per unit earnings ($0.28 in 2002 against $0.17 in 2001) and increased per unit cash available for distribution ($0.77 in 2002 against $0.73 in 2001).

2002 Activity Highlights In 2002, Algonquin Power Income Fund undertook the following initiatives aimed at increasing unitholder value:

Directly aligned management interests with unitholders in July, 2002 through a restructuring of the arrangements with the Manager providing senior management with a salary and incentive compensation plan;

Completed the acquisition of the KMS Power Income Fund in March, 2002 which includes the KMS Peel energy-from-waste facility, the KMS Crossroads cogeneration facility and the KMS Joliet landfill gas facility;

Completed the acquisition of the 44 MW Sanger, California cogeneration facility in May, 2002; and

Continued the expansion of the Infrastructure Division through the acquisition of three water reclamation and distribution utility companies in Arizona and Texas.

In 2002, the Fund completed acquisitions having a total value of $186.9 million.

2003 Outlook Summary While below average hydrologic conditions continued into the first quarter of 2003, the Fund believes that the continuing changes to the composition of its asset portfolio will allow the Fund to deliver sustainable and stable cash flows to unitholders. In early 2003, the Fund's operating divisions announced the following transactions in furtherance of achieving this objective and aimed at enhancing unitholder value. Completion of these transactions has allowed the Fund to commit fully the proceeds of previous public offerings of trust units:

- Acquisition of the 56 MW cogeneration facility in Windsor Locks, Connecticut;
- Acquisition of the 18,000 customer connection Litchfield Park, Arizona water reclamation and distribution facility;
- Agreements for the Fund to accept payment as consideration for lowering certain over-market power purchase rates stipulated in agreements in New Hampshire; and
- Agreement to acquire an interest in an 80 MW biomass fired generating facility in Virginia.

Assuming the completion of these transactions, the three generating divisions of the Fund are expected to contribute cash flows in approximately equal proportions. The Fund believes that such asset allocation, together with the Fund's current capital arrangements, will allow the Fund to deliver continued consistent distributions.

Significant Transactions During 2002, the Fund completed the acquisition of the KMS Power Income Fund (KMS). This acquisition added the 10 megawatt Peel energy-from-waste facility in Brampton, Ontario, the 10 megawatt Crossroads cogeneration facility in Mahwah, New Jersey and the 1.6 megawatt biogas generating facility in Joliet, Illinois. Another cogeneration facility located in Chicago, Illinois was sold during the year to the energy customer through the exercise of a purchase option in the energy services agreement. The Fund acquired all the outstanding trust units and 47.3% of the outstanding convertible debentures of KMS, by issuing 6,813,173 trust units. The Fund had previously loaned $35 million to KMS during 2001. The total transaction value of the acquisition was approximately $109.5 million.

- The Peel facility is a 10 MW generating facility which produces electricity from incinerating non-recyclable materials, including municipal solid waste, using steam to drive a turbine generator to produce electricity. It has a power purchase agreement with Ontario Electricity Financial Corporation which expires in 2012. The facility also has a waste supply agreement with the Regional Municipality of Peel which pays the facility to take approximately 162,000 tonnes of municipal solid waste annually and which expires in 2012.
- The Crossroads cogeneration facility has entered into a power purchase agreement expiring December 31, 2008 with Orange and Rockland Utilities Inc. for the purchase of up to 3.88 MW of electrical capacity. The facility also has an energy services agreement expiring in 2016 with Crossroads Corporate Park. It requires the facility to use reasonable efforts to provide firm electrical and thermal energy.
- The Joliet biogas generating facility is a landfill gas-to-electricity facility at the CDT landfill located near Joliet, Illinois. The facility is designed to generate approximately 1.6 MW of electricity. The facility has a power purchase agreement with Commonwealth Edison Company ("Com Ed"), a major mid-western utility company, whereby Com Ed will purchase all electricity produced by the facility under a one-year contract, automatically renewable yearly thereafter. Gas from 20 wells drilled in the CDT landfill is used by the facility.

The Fund added to its cogeneration portfolio by acquiring a 44 megawatt natural gas-fired cogeneration facility in Sanger, California. The facility has demonstrated a successful operating history since it was commissioned in 1991. Electrical energy and capacity produced by the facility are sold to Pacific Gas and Electric Company pursuant to a long-term power purchase agreement ending in May, 2021. Payments under the power purchase agreement consist of a monthly capacity payment and an energy payment which are fixed until 2006 at which time they become related to the cost of natural gas consumed by the facility. The Fund paid $46.9 million in cash, assumed $30.2 million (U.S. $19.4 million) in tax exempt municipal bonds and issued 248,667 trust units having a value of $2.2 million.

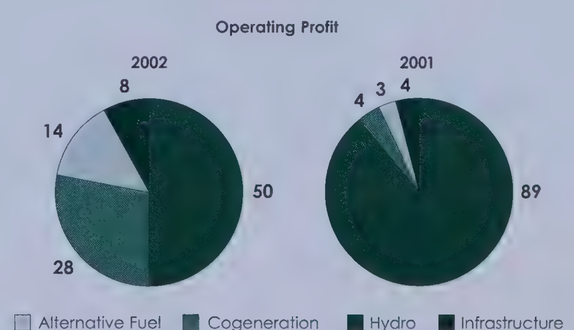
The Fund also added to its infrastructure portfolio during 2002 by acquiring the Bella Vista Water Company, Inc. in Sierra Vista, Arizona, for $21.6 million (U.S. $14.1 million) as well as the Tall Timbers and Woodmark water reclamation facilities in Tyler, Texas for a total of $5.5 million (U.S. $3.5 million). Together, these three acquisitions have a combined customer base of 8,590. The Fund now has a total of 13,500 water reclamation and distribution customers.

- The Bella Vista Water Company serves approximately 6,800 customers in the Town of Sierra Vista, approximately 100km southeast of Tucson, Arizona. Since its inception in 1954, Bella Vista has enjoyed the benefits of the steady expansion of the Town of Sierra Vista through growth in its customer base.
- The Tall Timbers water reclamation facility serves approximately 1,040 customers in the Town of Tyler, Texas, approximately 140 km east of Dallas, Texas.
- The Woodmark water reclamation facility serves approximately 750 customers in the Town of Tyler, Texas adjacent to the Tall Timbers facility.

Operating and Financial Review With continued expansion of the Cogeneration, Alternative Fuels and Infrastructure Divisions, the Fund repositioned its portfolio to increase its diversification from hydroelectric facilities.

Operating Results

During 2002, the Fund repositioned and balanced its portfolio to diversify the sources of operating profits before depreciation.



Hydroelectric Division

2002 Financial and Operating Highlights

Year ended December 31

All figures in thousands of dollars except as noted

	2002	2001	2003 Forecast Production (1)
Performance (MW-hrs sold)			
Quebec Region	**247,965**	251,810	297,800
Ontario Region (2)	**123,427**	111,093	130,800
New England Region	**48,001**	66,370	76,200
New York Region (2)	**66,512**	45,464	76,300
Western Region (2)	**48,120**	18,091	67,300
Total	**534,025**	492,828	648,400
Revenues			
Energy sales (3)	**40,681**	36,270	
Interest and dividend income	**674**	985	
	41,355	37,255	
Expenses			
Operating expenses (3)	**14,370**	12,420	
Division Operating Profit	**26,985**	24,835	
Average electricity sales price ($/MW-hr)	**76.21**	73.6	
Percentage of 2002 Forecast Production	**82%**	82%	

Notes:

(1) 2003 Forecast Production is based on hydrology records and past plant performance.

(2) 2001 energy production includes the Dickson Dam facility after acquisition in July, 2001 and five hydroelectric facilities located in Ontario, New York and Vermont after acquisition in early 2001.

(3) 2002 revenues and operating expenses include the costs for the full year of operations for those facilities acquired during 2001 (See note 2 above).

The Hydroelectric Division is comprised of 47 hydroelectric facilities located in the United States and Canada. Most facilities are run-of-the-river from which energy production is tied directly to available river flows. As a direct result of lower than average water flows, energy production in 2002 from the Fund's hydroelectric facilities was approximately 82% of long-term averages, consistent with 2001. Inclusion of 6 hydroelectric generating facilities acquired in 2001 for a full year in 2002 added approximately $1.3 million in revenue. The balance of the increase in revenue is the result of higher exchange rates between Canadian and U.S. currency during 2002.

Operating costs were $14.4 million, which were slightly lower than forecast due to lower regulatory and water lease fees resulting from lower production. Continued management emphasis is being placed on controlling costs and improving operational economies of scale. Operating costs were higher than the prior year due to the additional facilities and higher repair and maintenance and insurance costs. Major repairs were undertaken at the Belleterre, Donnaconna, Lochmere and Mine Falls generating stations, which resulted from unplanned breakdowns.

Hydroelectric Outlook For 2003 Colder than average temperatures causing below-average water flows in early 2003 have resulted in below-average energy production at the Hydroelectric Division's generating facilities. While snow pack levels are higher than average in regions in which the Fund's hydroelectric facilities are located, spring thaw characteristics will influence how effectively the Fund's facilities can capitalize on such potential.

The Fund has renegotiated with the Public Service Company of New Hampshire ("PSNH") the pricing terms of the power purchase agreements associated with 13 small hydroelectric generating facilities in New Hampshire. Subject to certain approvals and adjustments as consideration for a reduction in the above-market rates stipulated in these power purchase agreements, the Fund is expected to receive approximately $30.6 million (U.S. $20.4 million) after the first quarter. After completion of these transactions, PSNH will continue to purchase the energy produced by these generating stations at the New England power pool market price. Given the relatively short period of time remaining on these original agreements and considering the recent history of high volatility in water flow, the Fund believes that such capital will be more effectively deployed elsewhere within the Fund.

Cogeneration Division

2002 Financial and Operating Highlights

Year ended December 31

All figures in thousands of dollars except as noted

	2002	2001	2003 Forecast Production (1)
Performance (MW-hrs sold)	118,433	-	442,284
Revenues			
Capacity	11,310	-	
Energy sales	12,256	-	
Interest and dividend income	3,758	1,166	
	27,324	1,166	
Expenses			
Operating expenses	2,590	-	
Fuel expenses	9,665	-	
Division Operating Profit	15,069	1,166	
Average electricity sale price ($/MW-hr)	103.48		

Note:

(1) 2003 Forecast Production reflects forecast planned operating schedules based on existing permits and contracts and historic performance, including the March 2003 acquisition of the Windsor Locks facility.

The generating capacity of the Cogeneration Division was increased substantially in 2002 with the acquisition of the 44 MW Sanger cogeneration facility and the 10 MW KMS Crossroads facility. The 2002 performance of the Cogeneration Division assets was generally in accordance with expectations. Strong performance at the Sanger facility offset reduced production at the KMS Crossroads facility caused by unseasonably high temperatures in July and August and lost production arising from the completion of certain repairs at KMS Crossroads in September, 2002. The Cogeneration Division completed the major overhaul of the gas turbine at the KMS Crossroads facility during the second quarter of 2002. The investments in the Kirkland, Cochrane and Cardinal facilities contributed $3.8 million of dividends and interest compared to $1.2 million during 2001 as the revenue was included for the full year during 2002. These investments were made in October, 2001.

Cogeneration Outlook For 2003 In March, 2003, the Fund completed the acquisition of the 56 MW Windsor Locks, Connecticut cogeneration facility for $43.2 million (U.S. $29.5 million) which delivers electricity and thermal energy pursuant to sales agreements ending in 2011 and 2018, respectively. The facility delivers electricity to the Connecticut Light and Power Company pursuant to a long-term power purchase agreement ending in 2010. In addition, the facility delivers thermal steam energy and a small portion of its electrical energy to a specialty fiber composite mill located adjacent to the generating facility pursuant to an energy services agreement ending in 2018.

While the majority of the electrical output of the KMS Crossroads facility is sold pursuant to a long-term, take-or-pay power purchase agreement, increased building vacancy rates have resulted in lower electricity and thermal energy host sales by the KMS Crossroads facility which is expected to reduce 2003 contributions. In addition, gas supply to the facility was curtailed intermittently during the first quarter due to colder than normal temperatures in New Jersey.

Continued strong performance is expected throughout 2003 from the Sanger facility. The major overhaul for the Sanger facility will be completed in May, 2003. The projected cost of the overhaul has risen from $2.8 million to $4.0 million.

Alternative Fuels Division

2002 Financial and Operating Highlights

Year ended December 31

All figures in thousands of dollars except as noted

	2002	2001	2003 Forecast Production (1)
Performance (MW-hrs sold)	82,724	18,421	101,000
Performance (tonnes waste processed)	130,793		173,000
Revenues			
Energy sales	4,994	1,020	
Waste disposal sales	10,697	-	
Interest and dividend income	1,470	446	
	17,161	1,466	
Expenses			
Operating expenses	9,869	747	
Division Operating Profit	7,292	719	
Average electricity sale price ($/MW-hr) (2)	60.37	62.10	
Average waste tipping fee ($/tonne)	81.80		

Notes:

(1) 2003 Forecast Performance reflects forecast planned operating schedules based on existing permits and contracts and historic performance, but does not include any contribution from the previously announced pending acquisition of an interest in an 80 MW Virginia biomass-fired generating station by the Alternative Fuels division.

(2) Average electricity sale price in Canadian dollars includes the KMS Peel energy-from-waste facility and KMS Joliet landfill gas facility acquired on March 15, 2002 and a full year of operations of the Drayton Valley facility acquired in July, 2001.

Activity during 2002 in the Alternative Fuels Division was highlighted by the acquisition of the 10 MW KMS Peel 500 tonne/day energy-from-waste facility and the 1.6 MW KMS Joliet landfill gas facility. Management effort and resources were directed towards rectifying deferred maintenance problems and improving the cost control of the operation of these facilities. While in July, 2002, the KMS Peel facility commenced processing high value international airline waste, difficulties resulting from high moisture content of such waste stream reduced cash flows from this initiative through the balance of 2002. Unexpected steam turbine repairs completed in 2002 at the Drayton Valley biomass facility and the KMS Peel facility resulted in higher than expected repair/maintenance program costs.

Alternative Fuels Outlook For 2003 The handling charges levied by the KMS Peel facility for international airline waste were increased in April, 2003 to compensate for the high moisture content. The Fund anticipates that cash flows from this initiative will be in accordance with expectations through the balance of 2003.

In February, 2003, the Alternative Fuels Division announced that it had entered into an agreement to purchase a 40% partnership interest in an 80 MW biomass-fired electric generating station located in Virginia. The generating station has demonstrated a successful operating history since its commissioning in 1994 and provides peaking capacity to Virginia Electric and Power Company pursuant to a long-term capacity and energy purchase agreement ending in 2019. Closing of the acquisition of the partnership interest will be subject to, among other things, obtaining certain required transfer approvals.

Investment being made in capital improvements at the Drayton Valley biomass facility is focused on improving reliability. Increased downtime and cost to complete such work is expected to reduce its contribution in 2003. Management efforts are continuing to be focused on improving operational efficiencies at the KMS Peel and Drayton Valley facilities.

Infrastructure Division

2002 Financial and Operating Highlights

Year ended December 31

All figures in thousands of dollars except as noted

	2002	2001	2003 Forecast Connections (1)
Performance			
Water reclamation connections	**7,210**	4,600	17,850
Water distribution connections	**6,971**	-	18,500
Revenues			
Water reclamation	**4,827**	2,522	
Water distribution	**3,147**	-	
Interest and dividend income	**98**	30	
	8,072	2,552	
Expenses			
Operating expenses	**3,394**	1,353	
Division Operating Profit	**4,678**	1,199	

Note:

(1) 2003 Forecast Performance reflects current connections and management's assessment of current planned connection growth through a review of building permit issuances and includes the expected contribution of the Litchfield Park Service Company acquired in February, 2003.

The Infrastructure Division performed well in 2002 with customer growth and cash flows exceeding expectations. Compared with 2001, 2002 revenues increased by approximately $5.5 million and 2002 operating profit increased by approximately $3.5 million. These increases reflect primarily the effects of the acquisition of the Bella Vista Water Company in 2002 and the inclusion of the operations of the Gold Canyon Sewer Company and Black Mountain Sewer Company for a full year. In addition, the utilities in the Infrastructure Division demonstrated strong organic growth during 2002.

Infrastructure Outlook For 2003 In February, 2003, the Fund completed the acquisition of the Litchfield Park Service Company (LPSCo) for $52.5 million (U.S. $35.2 million). This utility provides the Fund with an additional 18,000 water reclamation and distribution connections. Recent acquisitions have propelled the Fund to its current position as the third largest investor-owned utility in Arizona.

Continued strong organic growth in the customer base of the Fund's water reclamation and distribution facilities is expected in 2003 with approximately 5,000 new connections forecast.

Administrative operations, including customer service and billing for the Fund utilities, are being consolidated at the Fund's head office in Oakville.

The Infrastructure Division was originally contemplated as a small diversification initiative to provide stable and growing cash flows to the Fund with downside protection afforded through the regulatory authorities. Opportunities in the high growth southwestern United States resulted in acquisitions that caused performance and capital requirements to exceed initial expectations. Accordingly, the Fund is actively considering a number of strategic alternatives for the Infrastructure Division, including the spin-off of this Division as a separately-traded entity.

Administration

Year ended December 31

All figures in thousands of dollars except as noted

	2002	2001
Administrative expenses		
Management costs	**658**	646
Administrative costs	**4,911**	792
Withholding taxes	**558**	472
Loss/(gain) on foreign exchange	**1,643**	(354)
Interest expense	**8,382**	6,700

During 2002, in recognition of the evolving governance standards in the income trust sector and the unique aspects of the Fund's business and structure, the Manager and the Fund voluntarily terminated the management agreements in respect of the Fund without compensation to the Manager. Under the revised agreements, while the senior management personnel are not technically employees of the Fund, compensation for these individuals is now limited to salary and an incentive bonus based solely on increases in cash available for distribution. Other management and operations services are now provided on a cost reimbursement basis.

Administration costs in 2002 were approximately $4.9 million, an increase of approximately $4.1 million over 2001. Such increased costs include approximately $1.2 million in non-recurring charges: legal costs incurred with respect to the Trafalgar Power Inc. and Franklin Industrial assets ($0.8 million); and additional GST due to a tax audit ($0.4 million). In 2001, administrative costs were reduced by franchise tax recovery ($0.8 million). The balance of the administrative cost increase over the prior year resulted primarily from the increased size of the Fund including the acquisition of the KMS Power Income Fund and associated administrative costs.

The Fund incurred a foreign exchange loss of $1.6 million of which approximately $1.0 million was unrealized. Foreign exchange gains and losses arise primarily from the long-term U.S. dollar denominated debt associated with the Sanger facility of $30.3 million (U.S. $19.2 million).

Interest and financing fees in 2002 totaled $8.4 million, an increase of $1.7 million over 2001. Such increased costs are related to increased activity in the Fund including use of the acquisition line of credit provided by the Fund's banking syndicate, the inclusion of project-related debt acquired during the year and the KMS convertible debentures.

Cash Flow

Year ended December 31

All figures in thousands of dollars except as noted

	2002	2001
Operating cash flow before working capital changes	**40,611**	22,173
Receipt of principal on notes receivable	**2,738**	8,414
Proceeds on sale of capital assets	**920**	-
Decrease in reserves	**1,854**	593
Repayment of long-term liabilities	**(929)**	(602)
Maintenance capital expenditures, net of capital grants	**59**	(1,565)
Other	**(511)**	(200)
Cash available for distribution	**44,742**	28,813
Distributions to unitholders	**55,192**	37,302
Per trust unit ($/trust unit)		
Cash available for distribution per trust unit	**0.77**	0.73
Distributions to unitholders per trust unit	**0.92**	0.92

Distributions declared to unitholders are generally based on the expected sustainable cash generated using long-term average water conditions for hydroelectric facilities and planned operations for non-hydroelectric generating assets. Cash distributions were $55.2 million in 2002 in comparison to $37.3 million in 2001. While performance of the recent acquisitions is forecast to provide accretion to cash available for distribution, as a result of below average hydrologic conditions in 2002, the Fund determined it was prudent to maintain the 2001 distribution level of $0.92 per unit in 2002.

Cash available for distribution does not have any standardized meaning prescribed by generally accepted accounting principles and is therefore unlikely to be comparable to similar measures presented by other companies.

Cash available for distribution generated by the Fund's portfolio increased by over 55% from $28.8 million in 2001 to $44.7 million in 2002. Per-unit results also increased by approximately 5% to $0.77 per unit in 2002 from $0.73 per unit in 2001. Management believes that such improvements can be traced directly to the Fund's diversification strategy.

Distribution Outlook for 2003 The Fund believes that current below-average hydrologic conditions are temporary. Therefore, long-term average energy production projections for the Fund's hydroelectric assets remain valid. There can be no assurances that the 2002 below-average water flow conditions will not continue into 2003. However, with the current diversification of the Fund's assets, less than 45% of 2003 cash distributions are forecast to be generated by the Hydroelectric Division. Forecast cash distributions to be provided from the other operating divisions are in excess of those amounts required to maintain current distribution levels.

Liquidity and Capital Reserves As at December 31, 2002, the Fund had positive net working capital of $15.4 million, compared to $19.0 million in 2001. At the end of 2002, the Fund had $24.8 million of cash and cash equivalents.

Long-term liabilities at December 31, 2002 were $85.2 million compared to $50.2 million in 2001. These long-term liabilities primarily represent the non-recourse project debt at certain facilities.

At the end of 2002, the Fund had a strong balance sheet with a debt-to-capital ratio of less than 15%.

Acquisitions completed by the Fund in early 2003 and the growth-capital expenditure requirements and equipment overhauls planned for 2003 will be financed from internally generated cash flows, cash received from the renegotiation of the New Hampshire power purchase contracts, funds from the public offering completed in October, 2002 and bank financing.

Risk Management Results from operations are affected by the exchange rate between the Canadian and U.S. dollars. The Fund has attempted to reduce the impact of exchange rate fluctuations by agreeing to pay certain of its obligations in U.S. dollars, including the Municipal Bonds for the Sanger facility. The Fund also utilizes forward contracts as required to fix the foreign exchange rate on cash flows for quarterly distributions and protect a minimum downside position. At the end of 2002, the Fund had forward contracts for U.S. $8.4 million or 75% of the U.S. dollar cash flow for 2003. In early 2003, the Fund entered into further forward contracts for U.S. $21.5 million or 44% of the U.S. dollar cash flow anticipated for 2004 to 2008.

The Fund's cogeneration and alternative fuels facilities utilize natural gas in their daily operating processes. The Fund has fixed its forecast gas consumption using natural gas fixed price contracts and future purchase contracts. The Fund has fixed its forecast natural gas exposure for 2003. The Sanger facility has fixed natural gas contracts in place until 2006 at which time the natural gas becomes a pass-through in the power purchase agreement. The Crossroads facility has effectively fixed the price on its natural gas price until May, 2004 at which time the natural gas becomes a pass-through in the power purchase agreement. The Peel energy-from-waste facility has fixed the price of its forecast usage of natural gas until 2007. Total MMbtu's being hedged during 2003 are approximately 1,600 per day.

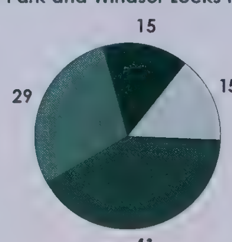
The Fund has adequate insurance on all of its facilities. This includes property and casualty, boiler and machinery and liability insurance.

Outlook The Fund will continue its diversification strategy to balance further and strengthen the portfolio during 2003.

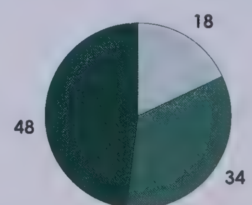
The Fund will continue to consider investment opportunities that provide stable cash flow from generating and infrastructure facilities. Opportunities that provide long-term, statistically predictable future cash flows and a risk profile generally consistent with the existing portfolio of assets, will be considered. All investment opportunities will continue to be required to meet the Fund's Acquisition Guidelines established by the Trustees. These guidelines provide that all acquisitions are expected to result in an increase in Distributable Cash per Trust Unit.

The Fund's portfolio will continue to be repositioned and balanced to reduce further the dependence on hydroelectric generation during 2003. The chart (below) shows the operating profit splits between the different groups after taking into account the transactions closed in the first quarter of 2003.

Expected Operating Profit before depreciation after completion of Litchfield Park and Windsor Locks transactions



Expected Operating Profit before depreciation after completion of Windsor Locks transaction excluding the Infrastructure Division



Alternative Fuel | Cogeneration | Hydro | Infrastructure

Quarterly Financial Information The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2002.

$ millions except per trust unit amount

2002	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Total
Revenues	15.7	28.4	25.1	25.6	94.8
Net earnings (loss)	6.1	10.3	(3.8)	3.6	16.2
Net earnings per trust unit (1)	0.12	0.18	(0.07)	0.05	0.28
2001	**1st Qtr**	**2nd Qtr**	**3rd Qtr**	**4th Qtr**	**Total**
Revenues	10.6	13.1	8.2	13.1	45.0
Net earnings (loss)	3.8	(2.5)	1.8	3.8	6.9
Net earnings per trust unit (1)	0.12	(0.08)	0.05	0.08	0.17

Note:

(1) The sum of net earnings per trust unit for the four quarters ended December 31 may differ from the net earnings per trust unit for the year due to difference in the average number of trust units outstanding.

Recently Issued U.S. and Canadian Accounting Standards In January, 2003, The Canadian Institute of Chartered Accountants ("CICA") issued "Handbook Section 3110, Accounting for Asset Retirement Obligations" which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Section 3110 requires the Fund to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The Fund is required and plans to adopt the provisions of Section 3110 as of January 1, 2004. The determination of fair value is complex and will require the Fund to gather market information and develop cash flow models. Because of the effort necessary to comply with the adoption of Section 3110, it is not practicable for management to estimate the impact of adopting this standard at the date of this report.

In December, 2002, the CICA issued Handbook Section 3063, "Impairment or Disposal of Long-Lived Assets" and revised Section 3475, "Disposal of Long-Lived Assets and Discontinued Operations." Together, these two Sections supersede the write-down and disposal provisions of Section 3061, "Property, Plant and Equipment" as well as Section 3475, "Discontinued Operations." Section 3063 amends existing guidance on long-lived asset impairment measurement and establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets held for use by the Fund. It requires that an impairment loss be recognized when the carrying amount of an asset to be held and used exceeds the sum of the undiscounted cash flows expected from its use and disposal; the impairment recognized is measured as the amount by which the carrying amount of the asset exceeds its fair value. Section 3475 requires assets classified as held-for-sale to be measured at the lower of their carrying amounts or fair value, less costs to sell. The new standards contained in Section 3063 on the impairment of long-lived assets held for use are applicable for years beginning on or after April 1, 2003. The revised standards contained in Section 3475 on disposal of long-lived assets and discontinued operations are applicable to disposal activities initiated by the Fund on or after May 1, 2003.

The CICA has issued Accounting Guideline 13, "Hedging Relationships" ("AcG 13") which establishes new criteria for hedge accounting and will apply to all hedging relationships in effect for the Fund on or after January 1, 2004. On January 1, 2004 the Fund will re-assess all hedging relationships to determine whether the criteria are met or not and will apply the new guidance on a prospective basis. To qualify for hedge accounting, the hedging relationship must be appropriately documented at the inception of the hedge and there must be reasonable assurance, both at the inception and throughout the term of the hedge, that the hedging relationship will be effective. Effectiveness requires a high correlation of changes in fair values or cash flows between the hedged item and the hedging item. The Fund is in the process of reviewing all of its hedging relationships to ensure compliance with the AcG-13 and does not anticipate any material impact from adopting this guideline at the date of this report.

In January, 2003, the CICA issued AcG 14 "Guarantees" which requires certain disclosures to be made by a guarantor in its interim and annual financial statements . The Fund will be required to make such disclosures in its first quarter 2003 financial statements. AcG-14 does not impact the Fund's operating results or financial position.

Note: Certain statements contained in the information herein are forward-looking and reflect the Fund's and its Manager's views with respect to future events. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Forward-looking statements are not guarantees of the Fund's future performance or results and are subject to various factors including but not limited to assumptions such as those relating to: the performance of the Fund's assets; commodity market prices; interest rates; and environmental and other regulatory requirements. Although the Fund and its Manager believe that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of the dates hereof. The Fund and its Manager are not obligated nor do either of them intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise.

Auditors' Report to the Unitholders

We have audited the consolidated balance sheets of Algonquin Power Income Fund as at December 31, 2002 and 2001 and the consolidated statements of earnings and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Toronto, Canada
March 24, 2003
(Except for Note 18 (d) which is as of April 22, 2003)

For the years ended December 31, 2002 and December 31, 2001

(THOUSANDS OF CANADIAN DOLLARS EXCEPT AS NOTED.)

	2002	2001
Assets		
Current assets		
Cash and cash equivalents	$ 24,838	$ 31,713
Accounts receivable	14,894	8,864
Prepaid expenses	692	477
Current portion of notes receivable (note 3)	1,317	1,176
Future income tax asset (note 10)	102	216
	41,843	42,446
Long term investments (note 3)	64,172	107,099
Future non-current income tax asset (note 10)	4,083	-
Capital assets, net of amortization (note 4)	547,880	357,118
Intangible assets, net of amortization (note 5)	61,126	1,919
Funds held in reserve	2,548	3,210
Deferred costs	1,386	592
	723,038	512,384
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	12,196	7,757
Due to Algonquin Power Group	1,241	2,324
Cash distribution payable	10,400	11,701
Current portion of long-term liabilities (notes 7 and 8)	1,355	498
Current income tax liability (note 10)	831	618
Future income tax liability (note 10)	444	537
	26,467	23,435
Long-term liabilities (note 7)	85,157	50,167
Other long-term obligations (note 8)	7,392	-
Deferred credits	5,752	1,410
Future non-current income tax liability (note 10)	46,839	25,759
Minority interest	13,660	-
Unitholders' equity		
Trust units (note 9)	638,213	473,013
Deficit	(100,442)	(61,400)
Commitments and contingencies (note 12)	537,771	411,613
	$ 723,038	$ 512,384

Approved by the Trustees

George Steeves

Mr. George Steeves

K Moore

Mr. Ken Moore

For the years ended December 31, 2002 and December 31, 2001

(THOUSANDS OF CANADIAN DOLLARS EXCEPT AS NOTED.)

	2002	2001
Revenue		
Energy sales	$ 69,241	$ 37,290
Waste disposal fees	10,697	-
Water reclamation and distribution revenue	7,974	2,522
Interest and dividend income	6,851	5,157
	94,763	44,969
Expenses		
Operating (note 11)	39,888	14,520
Amortization capital assets	17,206	9,777
Amortization intangible assets	3,173	454
Management costs (note 11)	658	646
Administrative expenses	4,911	792
Withholding taxes	558	472
(Gain)/loss on foreign exchange	1,643	(354)
	68,037	26,307
Earnings before undernoted	26,726	18,662
Interest expense	8,382	6,700
Loan payment fee	-	6,751
Income from note receivable prepayment	-	(1,890)
	8,382	11,561
Earnings before income taxes and minority interest	18,344	7,101
Current income taxes (note 10)	756	391
Future income taxes (note 10)	527	(154)
	1,283	237
Minority interest	911	-
Net earnings	16,150	6,864
Deficit, beginning of year	(61,400)	(30,962)
Cash distributions (note 14)	(55,192)	(37,302)
Deficit, end of year	$ (100,442)	$ (61,400)
Net earnings per trust unit (note 15)	$ 0.28	$ 0.17

For the years ended December 31, 2002 and December 31, 2001

(THOUSANDS OF CANADIAN DOLLARS EXCEPT AS NOTED.)

	2002	2001
Operating Activities		
Net earnings	$ 16,150	$ 6,864
Items not affecting cash		
Amortization of capital assets	17,217	9,777
Amortization of intangible assets	3,162	454
Other amortization	1,649	640
Minority interest	911	-
Distribution received in excess of equity income	30	163
Future income taxes	527	(154)
Loan prepayment fee	-	6,751
Income from note receivable prepayment	-	(1,890)
(Gain)/loss on foreign exchange	965	(432)
	40,611	22,173
Changes in non-cash operating working capital	(4,247)	7,405
	36,364	29,578
Financing Activities		
Cash distributions	(55,192)	(37,302)
Issue of trust units	98,504	235,150
Expenses of trust unit offerings	(5,525)	(12,658)
Deferred costs	(1,324)	(50)
Repayment of line of credit	(3,969)	-
Loan prepayment	-	(6,751)
Repayment of long-term liabilities	(929)	(22,702)
Deferred credits	1,152	-
	32,717	155,687
Investing Activities		
Decrease/(increase) in reserve funds	1,854	593
Receipt of principal on notes receivable	2,738	23,238
Acquisition of notes receivable and shares (note 2)	-	(74,534)
Additions to capital assets	(6,549)	(2,917)
Proceeds on sale of capital assets		920 -
Acquisition of operating entities (note 2)	(74,897)	(76,885)
KMS financing (note 2)	-	(35,000)
Receipt of financing fee	-	350
Income from note receivable prepayment	-	1,890
	(75,934)	(163,265)
Effect of exchange rate differences on cash and cash equivalents	(22)	133
Increase/(decrease) in cash	(6,875)	22,133
Cash and cash equivalents, beginning of year	31,713	9,580
Cash and cash equivalents, end of year	$ 24,838	$ 31,713
Supplemental disclosure of cash flow information		
Cash paid during the year for interest expense	$ 7,655	$ 6,594
Cash paid during the year for income taxes	$ 187	$ 191

(Thousands of Canadian dollars except as noted.)

Algonquin Power Income Fund (the "Fund") is an open-ended, unincorporated trust established pursuant to the Declaration of Trust dated September 8, 1997, as amended, under the laws of the Province of Ontario. The Fund's principal business activity is the ownership, directly or indirectly, of generating and infrastructure facilities.

The Fund is managed by Algonquin Power Management Inc. ("APMI"), a company wholly owned by the shareholders of Algonquin Power Corporation Inc. ("APC"). A subsidiary of APC, Algonquin Power Systems Inc. ("APS"), is responsible for the operation of many of the Fund's facilities. Algonquin Power Acquisition Partnership, a partnership ultimately owned by APC, provides consulting services to the Fund. Newspring Limited Partnership ("Newspring"), a partnership jointly owned by APC and a third party, manages and operates the water reclamation and distribution facilities in Arizona. Collectively, these entities are referred to as the Algonquin Power Group.

1. Significant accounting policies

(a) Basis of consolidation

The consolidated financial statements of the Fund have been prepared in accordance with accounting principles generally accepted in Canada and include the consolidated accounts of all of its subsidiaries. The Fund consolidates its proportionate share in the Campbellford Limited Partnership and the Valley Power Limited Partnership.

All significant intercompany transactions and balances have been eliminated.

(b) Cash and cash equivalents

Cash and cash equivalents include cash deposited at banks and highly-liquid investments with original maturities of 90 days or less.

(c) Funds held in reserve

Cash reserves segregated from the Fund's cash balances are maintained in accounts administered by a separate agent and disclosed separately in these consolidated financial statements as the Fund cannot access this cash without the prior authorization of parties not related to the Fund.

(d) Capital assets

Capital assets, being land, facilities and equipment, are recorded at cost. Development costs, including the cost of acquiring or constructing facilities together with the related interest costs during the period of construction are capitalized. Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

The facilities are amortized on a straight-line basis over their estimated useful lives. These periods range from 15 to 40 years. Facility equipment is amortized over 5 years.

(e) Intangible assets

Power purchase contracts acquired are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 15 years.

The costs attributable to establishing exemptions from Federal Energy Regulatory Commission licensing requirements in the United States are being amortized on a straight-line basis over five years.

Hydro contract acquisition costs are amortized on a straight-line basis over 6 years.

(f) Impairment of long-lived assets

The Fund reviews capital assets and intangible assets for permanent impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. Recoverability is measured by comparing the carrying amount of an asset to expected future cash flows. If the carrying amount exceeds the expected future cash flows, the asset is written down.

(g) Notes receivable

Notes receivable are carried at cost. A provision for credit losses on notes receivable is charged to the statement of earnings and deficit to cover any losses of principal and accrued interest.

(h) Deferred costs

Deferred costs, which include the costs of arranging the credit facility, costs associated with periodic customer rate reviews with the utility governing bodies for the water reclamation and distribution facilities and costs of various reorganizations which provide benefits for a number of years, are amortized on a straight-line basis over the term of the expected benefit being 2 to 5 years.

(i) Long-term investments

Investments in which the Fund has significant influence but not control or joint control are accounted using the equity method. The Fund records its share in the income or loss of its investees in interest and dividend income in the consolidated statement of earnings and deficit. All other equity investments are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and are adjusted only for other-than-temporary declines in fair value, distributions of earnings and additional investments.

(j) Deferred credits

Certain of the water companies receive customer advances for water and sewage main extensions. The amounts advanced are generally repaid over a period of 10 years based on 10% of the revenues generated by housing/development in the area developed. Advances not refunded within ten years are not required to be repaid. These non-refunded amounts are credited against capital assets. When the Fund receives contributions in aid of construction with no repayment terms, these are immediately treated as a capital grant and netted against capital assets.

Deferred water rights result from a hydroelectric generating facility that has a fifty-year water lease with the first ten years of the water lease requiring no payment. An average rate was estimated over the life of the lease and an accrual is booked based on this estimate that will be drawn down in the last forty years.

(k) Recognition of revenue

Revenue derived from energy sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Water reclamation and distributions revenues are recorded when billed to customers.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts are recognized based on actual tonnage at the expected price for the contract year and any amount billed in excess of the expected rate is the expected price for the contract year and any amount billed in excess of the expected rate is deferred.

Interest and dividend income from long-term investments is recorded as earned.

(l) Foreign currency translation

The Fund's United States subsidiaries and partnership interests are considered to be functionally integrated with the Canadian operations. All monetary assets and liabilities denominated in United States dollars are translated into Canadian dollars at year-end exchange rates, whereas non-monetary assets and liabilities are translated at the rate in effect at the transaction date. The revenues and expenses of these integrated operations are translated at the average rate of exchange in effect during the period. The foreign currency translation adjustment is reflected in the consolidated statement of earnings and deficit.

(m) Derivatives contracts

The Fund enters into forward contracts and swap contracts to hedge against possible fluctuations in commodity prices. Gains and losses from these activities are reported as adjustments to the related revenue or expense account as they are settled.

The Fund also enters into forward contracts to manage its exposure to the U.S. dollar. These contracts are not for speculative purposes. The Fund carries these contracts at fair value with changes in fair value reflected in the consolidated statement of earnings and deficit.

(n) Income taxes

As the Fund is an unincorporated trust, it is entitled to deduct distributions to unitholders to the extent of its taxable income and consequently, it is expected that the Fund will not be liable for any material tax as this will be the responsibility of the individual unitholder. Any provision for income taxes will relate solely to the income taxes of the Fund's wholly owned subsidiaries.

Income taxes are accounted for using the asset and liability method. Future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

(o) Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of capital assets and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of future tax assets, and the fair value of financial instruments and derivatives. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(p) Comparative Figures

Certain comparative figures have been re-classified to conform to the current year presentation.

2. Acquisitions

(a) Acquisitions of facilities

On July 4, 2002, the Fund completed the acquisition of all the outstanding trust units of KMS Power Income Fund ("KMS") not already owned. The Fund had initially acquired 86.7% of the outstanding trust units and 47.3% of the outstanding principal amount of convertible debentures of KMS on March 15, 2002. KMS owns directly or indirectly, four power generation facilities: an energy-from-waste facility in Ontario; two natural gas-fired cogeneration facilities located in New Jersey and Illinois; and a landfill biogas-fired generating facility in Illinois.

On May 1, 2002, the Fund acquired a natural gas-fired generating station located in Sanger, California for $49,035 (U.S. $31,475).

Through its Infrastructure Division, the Fund acquired the shares of a water distribution company in Sierra Vista, Arizona on May 23, 2002 for $21,600 (U.S. $14,086) and two water reclamation companies in Tyler, Texas on November 5, 2002 for $3,419 (U.S. $2,196) and December 18, 2002 for $2,096 (U.S. $1,350).

In 2002, the Fund paid an additional $1,311 (U.S. $862) for a water reclamation facility acquired in the third quarter of 2001, as a result of a rate case which was in progress at the time of the initial acquisition. This acquisition has further contingent payments based on the level of growth in the customer base during the period from July 1, 2002 to July 1, 2003.

The consideration paid by the Fund has been allocated to net assets acquired as follows:

	KMS	Sanger	Infrastructure	Total
Working capital	$ (4,357)	$ 350	$ 2,694	$ (1,313)
Funds held in reserve	1,125	-	67	1,192
Other assets	425	77	-	502
Capital assets	88,321	66,929	44,835	200,085
Intangible assets	46,713	14,925	731	62,369
Long term liabilities assumed	(2,806)	(30,403)	(3,629)	(36,838)
Other long term obligations assumed	(4,172)	(2,843)	(328)	(7,343)
Deferred credits	-	-	(2,563)	(2,563)
Minority interest	(13,001)	-	-	(13,001)
Future non-current tax asset	3,610	-	-	3,610
Future non-current income tax liability	(6,374)	-	(13,381)	(19,755)
Total purchase price	109,484	49,035	28,426	186,945
Less: cash acquired	(1,785)	-	(3,042)	(4,827)
Loan advanced in 2001 (note 3)	(35,000)	-	-	(35,000)
Trust units issued being non cash consideration (note 9)	(70,040)	(2,181)	-	(72,221)
Cash consideration	$ 2,659	$ 46,854	$ 25,384	$ 74,897

Facility	Purchase Price	Nature of Acquisition	Date of Acquisition
KMS Peel, Ontario, KMS Crossroads, New Jersey, KMS Bakery, Illinois and KMS Joliet, Illinois	$ 109,484	Trust units and convertible debentures	March 15, 2002 and July 4, 2002
Sanger, California	49,035	Assets	May 1, 2002
Bella Vista, Arizona	21,600	Shares	May 23, 2002
Tall Timbers, Texas	3,419	Shares	November 5, 2002
Woodmark, Texas	2,096	Shares	December 18, 2002
Gold Canyon, Arizona	1,311	Shares	September 19, 2002
Total	$ 186,945		

Subsequent to the acquisition of KMS, under the terms of the Energy Services Contract between the cogeneration facility located in Illinois and the energy customer, the energy customer purchased the plant and equipment for $920 (U.S. $588). No gain or loss was recognized as the assets were appropriately written down at the acquisition date to their realizable value.

The purchase price allocation has been based on the best information available at the reporting date; however, adjustments to the purchase price and purchase price allocation may be made in subsequent quarters as more information is obtained.

During 2001, the Fund acquired the assets of Drayton Valley Power Income Fund which contributed one hydroelectric generating facility and a 50% ownership in a biomass generating facility. Through its Hydroelectric Division, the Fund acquired five hydroelectric generating facilities, a note receivable and a 50% interest in a hydroelectric generating facility. Through its Infrastructure Division, the Fund acquired two water reclamation and distribution facilities in Arizona. The acquisitions have been accounted for using the purchase method with earnings from operations included since the date of acquisition. The consideration paid by the Fund has been allocated to net assets acquired as follows:

	Drayton	Hydro	Infrastructure	Total
Working capital	$ 794	$ 645	$ (60)	$ 1,379
Funds held in reserve	-	-	2,107	2,107
Capital assets	41,324	21,699	11,307	74,330
Note receivable	-	3,680	-	3,680
Future non current tax asset	-	-	802	802
Future non current income tax liability	-	(5,354)	(59)	(5,413)
Cash consideration	$ 42,118	$ 20,670	$ 14,097	$ 76,885

Facility	Purchase Price	Nature of Acquisition	Date of Acquisition
Phoenix Hydro, Kings Falls and Otter Creek, New York State and Worcester Hydro, Vermont	$ 11,614	Shares	March 21, 2001
Campbellford, Ontario	8,151	Partnership interest and note receivable	March 9, 2001 and April 1, 2001
St Raphael de Bellchasse, Quebec	905	Shares	April 11, 2001
Black Mountain Sewer, Arizona	6,782	Shares	March 16, 2001
Gold Canyon Sewer, Arizona	7,315	Shares	July 9, 2001
Dickson Dam and 50% of Valley Power, Alberta	42,118	Trust units	July 27, 2001
Total	$ 76,885		

(b) Acquisition of notes receivable and shares

During the fourth quarter of 2001, the Fund acquired certain notes receivable and shares in six generating facilities for a total of $74,534. These included three biomass-fired generating facilities in Alberta, Quebec and Nova Scotia and three gas-fired cogeneration facilities located in Ontario.

Subsequent to the completion of this transaction the owner of one facility, a biomass facility located in Alberta, repaid the outstanding loan plus a prepayment penalty. The Fund has no further interest in this facility.

(c) Other

i) The management agreement with APMI was changed effective July 1, 2002, to eliminate any fees on acquisitions (see Note 11 (a)). Prior to July 1, 2002, the Fund paid the Algonquin Power Group fees totalling $2,982 (2001 - $2,178) for the acquisition of KMS, Sanger and Bella Vista Water Company, Inc. representing a total transaction value of $180,119 (2001 - $123,967).

ii) During the fourth quarter of 2001, the Fund entered into a loan agreement with KMS. The Fund advanced $35,000 at an interest rate of 5.568% above prime.

iii) In 2001, the Fund acquired from the Algonquin Power Group the 50% interest in the Campbellford Limited Partnership, St Raphael de Bellchasse, Phoenix Hydro, Otter Creek, Kings Falls, Worcester Hydro and Black Mountain Sewer for a total cash consideration of $20,101.

3. Long-term investments

	2002	2001
Debt and share interests in five generating facilities, ranging from 12.1% to 32.4% interests	$ 55,265	$ 57,788
A 45% partnership interest in the Algonquin Power (Rattle Brook) Partnership	3,894	3,937
	59,159	61,725
KMS Loan		
Interest at a floating rate of 5.568% above prime. Payments consist of interest only prior to maturity. Maturity is November, 2004.	-	35,000
Campbellford Note Note bearing interest of 9.9415% repayable in monthly blended installments of $32, maturing February 28, 2015.	3,389	3,554
Other	2,941	7,996
	6,330	46,550
	65,489	108,275
Less: current portion	1,317	1,176
	$ 64,172	$107,099

The above notes are secured by the underlying assets of the respective facilities.

4. Capital assets

	2002 Cost	2002 Accumulated amortization	2002 Net book value	2001 Net book value
Land	$ 7,825	$ -	$ 7,825	$ 1,338
Facilities	575,312	39,467	535,845	354,215
Equipment	4,960	750	4,210	1,565
	$ 588,097	$ 40,217	$ 547,880	$ 357,118

Facilities include $91,278 (2001 – $92,439) of net assets under capital lease.

Facilities also includes a turbine with a carrying value of $2,262 which is not in use and consequently is not being amortized.

5. Intangible assets

	2002 Cost	2002 Accumulated amortization	2002 Net book value	2001 Net book value
Power purchase contracts	$ 61,649	$ 2,733	$ 58,916	$ -
Hydro contract acquisition costs	1,442	1,211	231	461
Customer relationships	731	11	720	-
Licenses and agreements	1,878	619	1,259	1,458
	$ 65,700	$ 4,574	$ 61,126	$ 1,919

6. Revolving credit facility

The Fund has negotiated a $100 million revolving credit facility with a syndicate of Canadian banks, which will mature April 26, 2004. Under the terms of the revolving credit facility, the Fund may acquire generating or infrastructure facilities which meet the Fund's acquisition guidelines. At December 31, 2002, the Fund had not drawn any funds (2001 - $0) on the facility, with the exception of certain letters of guarantee totaling $31,726 (2001 - $4,174), posted as security. During 2002, the Fund had a maximum drawn on the line of $65,627 (2001 - $41,943). The terms of the credit agreement require the Fund to pay a standby charge of 0.425% on the unused portion of the revolving credit facility and maintain certain financial covenants. The facility is secured by a fixed and floating charge over all Fund entities.

A wholly owned trust of the Fund has an established credit facility for letters of credit up to an aggregate maximum of $5,000. Under the terms of the credit facility, the trust must meet certain financial covenants. At December 31, 2002, the trust has outstanding letters of credit totaling $4,519.

7. Long-term liabilities

	2002	2001
Senior Debt Long Sault Rapids Interest at rates varying from 10.16% to 10.21% repayable in monthly blended installments of $401, maturing December, 2028.	$ 44,071	$ 44,397
Senior Debt Chute Ford Interest rate of 11.55% repayable in monthly blended installments of $64, maturing April, 2020.	5,706	5,804
Sanger Bonds California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, payable monthly, maturing September, 2020. U.S. $19,200.	30,328	-
KMS Convertible Debentures Interest rate of 10% interest payable semi-annually June and December, maturing June, 2004.	2,150	-
Bella Vista Water loans Water Infrastructure Financing Authority of Arizona Interest rates of 6.10% and 6.26% repayable in monthly and quarterly installments, maturing September, 2018 and June, 2021. U.S. $153 and $1,997, respectively.	3,397	-
Other	447	464
	$ 86,099	$ 50,665
Less: current portion	(942)	(498)
	$ 85,157	$ 50,167

Each of the senior debt is secured by the respective facility with no other recourse to the Fund. The loans have certain financial covenants which must be maintained on a quarterly basis.

Starting June 30, 2002, the KMS convertible debentures may be redeemed in whole or in part at the option of KMS for the principal amount plus accrued interest, provided the current market price preceding the date of the notice of redemption is not less then 115% of the conversion price. The debentures are convertible to KMS trust units at the option of the holder at a conversion price of $11.00 per trust unit until maturity.

Principal payments due in the next five years are:		
	2003	$ 942
	2004	3,076
	2005	984
	2006	1,022
	2007	1,068
	Thereafter	79,007
		$ 86,099

8. Other long-term liabilities

	2002	2001
Joliet Subsidy Loan In accordance with Illinois law, a significant portion of the revenue received by KMS Joliet for the sale of electricity to the utility represents a subsidy. Repayment arrangements satisfactory to the State of Illinois must be implemented by 2007.	$ 4,077	$ -
Melo Roos Obligation for real estate taxes for the Sanger plant due October 1, 2011 at interest rates varying from 4.75% to 5.55%.	2,654	-
Other	1,074	-
	$ 7,805	$ -
Less: current portion	(413)	-
	$ 7,392	$ -

9. Trust units

Authorized trust units

The Declaration of Trust provides that an unlimited number of units may be issued. Each unit represents an undivided beneficial interest in any distribution from the Fund and in the net assets in the event of termination or wind-up. All units are the same class with equal rights and privileges.

Trust units are redeemable at the holder's option at amounts related to market prices at the time subject to a maximum of $250 in cash redemptions in any particular calendar month. Redemptions in excess of this amount shall be paid by way of a distribution in specie of a pro rata amount of certain of the Fund's assets, including the securities purchased by the Fund, but not to include the generating facilities.

Issued trust units	**Number of units**	**Amount**
Balance as at December 31, 2000	27,020,472	$ 250,521
Issued during the year for cash	23,855,300	235,150
Cost of issue		(12,658)
Balance as at December 31, 2001	50,875,772	473,013
Issued during the year for cash	9,950,000	98,504
Issued pursuant to acquisition of KMS and Sanger (note 2)	7,061,840	72,221
Cost of issues		(5,525)
Balance as at December 31, 2002	67,887,612	$ 638,213

The Fund completed one public offering in 2002 and three public offerings in 2001.

10. Income taxes

The provision for income taxes in the consolidated statements of earnings represents an effective tax rate different than the Canadian statutory rate of 37.2% (2001 - 38.0%). The differences are as follows:

	2002	2001
Earnings before income tax and minority interest	$ 18,344	$ 7,101
Less: income taxed directly in hands of unitholders, not the Fund	(22,068)	(3,341)
Earnings/(loss) of subsidiaries	(3,724)	3,760
Computed income tax expense at Canadian statutory rate	(1,385)	1,429
Increase (decrease) resulting from:		
Change in substantively enacted tax rate	-	(660)
Manufacturing and processing deduction	(372)	(95)
Large corporations tax and alternative minimum tax	355	112
Other	2,158	(549)
Income tax expense	$ 756	$ 237

The tax effect of temporary differences at the Fund's subsidiaries that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2002 and 2001 are presented below:

	2002	2001
Future tax assets:		
Non-capital loss, debt restructuring charges and non-deductible interest carryforwards	$ 13,349	$ 3,221
Other	235	-
Total future tax assets	13,584	3,221
Less: Valuation allowance	(5,174)	-
	$ 8,410	$ 3,221
Future tax liabilities:		
Capital assets –differences between net book value and undepreciated capital cost	$ (42,781)	$ (29,301)
Intangible assets – difference between net book value and cumulative eligible capital	(8,727)	-
Total future tax liabilities	(51,508)	(29,301)
Net future tax liability	$ (43,098)	$ (26,080)
Classified in the financial statements as:		
Future current income tax asset	$ 102	$ 216
Future non-current income tax asset	4,083	-
Future current income tax liability	(444)	(537)
Future non-current income tax liability	(46,839)	(25,759)
	$ (43,098)	$ (26,080)

At December 31, 2002, the Fund itself has financing expenses and underwriters' fees of $14,670 (2001 - $16,889) which will be deductible by the Fund and which will reduce the ultimate amount taxable to the unitholders over the next four years. This will be offset by additions to the unitholders' taxable income since the Fund's capital assets have an accounting basis which exceeds their tax basis by $4,270 (2001 - $3,265). In addition, two trusts wholly owned by the Fund have capital assets with an accounting basis which exceeds their tax basis by $6,044 (2001 - $1,602).

11. Algonquin Power Group

(a) Management Agreement

The Fund has agreed to management arrangements with APMI. The management services to be provided include advice and consultation concerning business planning, support, guidance and policy making and general management services. During 2002, these arrangements were amended to be on a cost recovery basis rather than a fee basis. The amended arrangements provide for an incentive fee of 25% on all distributable cash generated in excess of $0.92 per trust unit. During 2002 and 2001 no incentive fees were earned by APMI.

During 2002, APMI charged $658 (2001 - $646) for management services.

(b) Operations

Many of the Fund's power generating facilities have direct operations contracts with APS. The direct operations contracts provide for the day-to-day services required to operate and maintain the facilities in addition to planning of capital repairs, compliance monitoring for environmental permits and administration of power purchase agreements. In 2002, APS was paid on a cost recovery basis for all costs incurred as opposed to a fee basis in 2001.

During 2002, APS charged $10,238 (2001 - $6,745) for direct operation services.

(c) Water reclamation and distribution

The water reclamation and distribution facilities have direct operations contracts with Newspring. The direct operations contracts provide for the day-to-day services required to operate and maintain the facilities. In 2002, Newspring was paid on a cost recovery basis for all costs incurred as opposed to a fee basis in 2001.

During 2002, Newspring charged $1,847 (2001 - $418) for direct operation services.

(d) Other

During the year the Fund reimbursed APC $750 for legal fees paid by APC to outside counsel.

12. Commitments and Contingencies

(a) Land and Water Leases

Each of the operating entities has entered into agreements to lease either the land and/or the water rights for the hydroelectric generating facility or to pay in lieu of property tax an amount based on electricity production. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. The Fund incurred $2,474 during 2002 (2001 - $2,293) in respect of these agreements for the consolidated facilities.

(b) Contingencies

The Fund and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider the Fund's exposure to such litigation to be material to these financial statements.

13. Fair Value of Financial Instruments and Derivatives

The carrying amount of the Fund's cash and cash equivalents, accounts receivable, funds held in reserve, accounts payable, accrued liabilities, due to Algonquin Power Group and cash distribution payable, approximate fair market value due to the short term nature of these financial instruments.

The carrying amount of the Fund's long-term investments is dependent on the underlying operations and accordingly a fair value is not readily available. The Fund has long-term debt at fixed interest rates. The fair value of these loans at current rates would be $100,888 (2001- $64,052). The fair value of other long-term liabilities approximates their carrying value.

The Fund's energy-from-waste facility in Peel entered into natural gas purchase contracts whereby the facility has agreed to purchase 351 GJ of gas per day from November, 2001 to October, 2004 at contract rates ranging from U.S. $3.35 to U.S. $3.55 per GJ excluding transportation. The facility has also entered into additional natural gas purchase contracts whereby the entity has agreed to purchase 333 mmbtu of natural gas per day from November, 2004 to October, 2007 at contract rates ranging from U.S. $4.16 to U.S. $4.30 per mmbtu including transportation. The market price per GJ was $5.97 at December 31, 2002 (2001 - $4.48 per GJ). The fair value of the outstanding futures contracts is U.S.$295 at December 31, 2002.

The Fund's cogeneration facility in Sanger, California entered into natural gas purchase contracts whereby the facility has agreed to purchase 5,500 mmbtus per weekday from December 31, 2002 to July 31, 2006 at the rate of U.S. $4.52 per mmbtus. The market price per mmbtus was U.S. $4.64 at December 31, 2002. The fair value of the outstanding futures contract is U.S. $607 at December 31, 2002.

The Fund's cogeneration facility in Mahwah, New Jersey entered into price swap contracts to fix the price paid for a portion of the natural gas purchases for the facility. The contracts fix the price of natural gas at U.S. $3.96 per mmbtu for 22,000 mmbtus per month from May, 2002 to April, 2003 and at U.S. $4.30 per mmbtu for 22,000 mmbtus per month from May, 2003 to April, 2004. Each month there is a settlement on the difference between the fixed price and the spot price based on the Texas Eastern M-3 price. The Texas Eastern M-3 price at December 31, 2002 was U.S. $5.22 per mmbtu. The fair value of the contract is U.S. $355 at December 31, 2002.

The Fund has entered into foreign exchange contracts to manage its exposure to the U.S. dollar as significant cash flows are generated in the U.S. The Fund sells specific amounts of currencies at predetermined dates and exchange rates which are matched with the anticipated operational cash flows. Contracts in place at December 31, 2002 include selling U.S. $8,400 in 2003 at a weighted average exchange rate of $1.58. The fair value of the outstanding futures contracts is ($25) at December 31, 2002.

14. Cash distributions

Prior to October , 2002, distributable income, as defined in the Declaration of Trust, was distributed to unitholders of record on the last day of each calendar quarter on or before the 45th day of the following calendar quarter. The frequency of cash distributions was changed from quarterly to monthly commencing with the month of October, 2002. Distributions are declared to unitholders of record on the last day of the month and are distributed 45 days after declaration. The monthly distribution was $0.0766 per trust unit for each month for a total of $0.23 for the quarter.

Distributions per unit declared by the Trustees in 2002 and 2001 were as follows:

	2002	2001
First quarter	$ 0.23	$ 0.23
Second quarter	$ 0.23	$ 0.23
Third quarter	$ 0.23	$ 0.23
Fourth quarter	$ 0.23	$ 0.23

15. Basic and diluted net earnings per trust unit

Net earnings per trust unit has been calculated using the weighted average number of units outstanding during the year. The weighted average number of units outstanding for 2002 was 58,346,032 (2001 – 39,524,548). The net earnings per trust unit for 2002 was $0.28 (2001 - $0.17). The effect of conversion of the KMS convertible debentures into trust units was not included in the computation of fully diluted net earnings per trust unit as the effect of conversion would be anti-dilutive.

16. Segmented Information

	2002	2001
Revenue		
Canada	$ 48,312	$ 28,845
United States	46,451	16,124
	$ 94,763	$ 44,969
Capital assets		
Canada	$ 336,897	$ 262,235
United States	210,983	94,883
	$ 547,880	$ 357,118
Intangible assets		
Canada	$ 31,134	$ 461
United States	29,992	1,458
	$ 61,126	$ 1,919

Revenues are attributable to the two countries based on the location of the underlying generating and infrastructure facilities.

Operational segments

The Fund identifies four business categories it operates in: hydro; natural gas cogeneration; alternative fuels; and infrastructure assets. The operations and assets for these segments are outlined on the following page:

12 Months ended December 31st, 2002

Revenue	Hydro	Cogeneration	Alternative Fuels	Infrastructure	Administration	Total
Energy sales	40,681	23,566	4,994	-	-	69,241
Waste disposal fees	-	-	10,697	-	-	10,697
Water reclamation and distribution	-	-	-	7,974	-	7,974
Interest and dividend income	674	3,758	1,470	98	851	6,851
Total Revenue	41,355	27,324	17,161	8,072	851	94,763
Operating expenses	14,370	12,255	9,869	3,394	-	39,888
Operating profit	26,985	15,069	7,292	4,678	851	54,875
Other administration costs	(371)	-	(286)	(63)	(7,050)	(7,770)
Interest expense	(5,234)	(479)	(539)	(140)	(1,990)	(8,382)
Amortization of capital assets	(10,290)	(2,339)	(3,332)	(1,245)	-	(17,206)
Amortization of intangible assets	(428)	(1,193)	(1,541)	(11)	-	(3,173)
Earnings before income taxes and minority interest	10,662	11,058	1,594	3,219	(8,189)	18,344
Capital assets	333,431	62,726	92,947	58,776	-	547,880
Intangible assets	1,490	26,428	32,488	720	-	61,126
Capital expenditures	684	68,503	89,695	47,752	-	206,634
Intangible expenditures	-	27,620	34,018	731	-	62,369

12 Months ended December 31st, 2001

Revenue	Hydro	Cogeneration	Alternative Fuels	Infrastructure	Administration	Total
Energy sales	36,270	-	1,020	-	-	37,290
Waste disposal fees	-	-	-	-	-	-
Water reclamation and distribution	-	-	-	2,522	-	2,522
Interest and dividend income	985	1,166	446	30	2,530	5,157
Total Revenue	37,255	1,166	1,466	2,552	2,530	44,969
Operating expenses	12,420	-	747	1,353	-	14,520
Operating profit	24,835	1,166	719	1,199	2,530	30,449
Other administration expenses	765	-	-	-	(2,321)	(1,556)
Interest expense	(6,102)	-	-	-	(598)	(6,700)
Loan prepayment fee	(6,751)	-	-	-	-	(6,751)
Income from note receivable prepayment	-	-	1,890	-	-	1,890
Amortization of capital assets	(9,394)	-	(199)	(184)	-	(9,777)
Amortization of intangible assets	(454)	-	-	-	-	(454)
Earnings before income taxes and minority interest	2,899	1,166	2,410	1,015	(389)	7,101
Capital assets	335,304	-	9,360	12,454	-	357,118
Intangible assets	1,919	-	-	-	-	1,919
Capital expenditures	55,029	-	9,560	12,658	-	77,247

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2002 or 2001: Niagara Mohawk Power Corporation 7% (2001 - 10%), Ontario Electricity Financial Corporation 15% (2001 - 19%), Public Service of New Hampshire 12% (2001 - 23%), Hydro Québec 22% (2001 - 38%), Pacific Gas and Electric 26% (2001 - 0%). The Fund has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.s

17. Joint Venture Investments

	Ownership Interest	Fund's Proportionate Share: Income Before Income Tax, Year ended December 31, 2002	2001	Net Assets, December 31, 2002	2001
Valley Power Limited Partnership	50%	$ 70	$ 52	$ 9,801	$ 10,196
Campbellford Limited Partnership	50%	$ 244	$ 108	$ 4,177	$ 4,326
		$ 314	$ 160	$13,978	$ 14,522

The Fund acquired its interests in both entities during 2001.

18. Subsequent Events

(a) Subsequent to the end of the year, the Fund acquired a 56 megawatt cogeneration facility in Windsor Locks, Connecticut for $43,200 (U.S. $29,500) to be satisfied by cash. This facility sells electricity to Connecticut Light and Power Company pursuant to a long-term power purchase agreement ending in 2010. In addition, the facility delivers steam energy and a small portion of electricity to a specialty fiber composites mill located adjacent to the facility.

(b) The Fund acquired Litchfield Park Service Company located outside of Phoenix, Arizona for $52,500 (U.S. $35,200) which will be satisfied by the assumption of $19,400 (U.S. $12,455) of fixed interest, tax exempt bonds and the balance in cash. The company currently services approximately 18,000 water reclamation and distribution customers.

(c) In February, 2003, the Alternative Fuels Division announced that it had entered into an agreement to purchase a 40% partnership interest in an 80 MW biomass-fired electric generating facility located in Virginia. The generating facility has demonstrated a successful operating history since its commissioning in 1994 and provides peaking capacity to Virginia Electric and Power Company pursuant to a long-term capacity and energy purchase agreement ending in 2019. Under the terms of the purchase and sale agreement the Fund cannot disclose the details of the transaction prior to closing. Closing of the acquisition of the partnership interest will be subject to, among other things, obtaining certain required transfer approvals.

(d) The Fund has renegotiated with the Public Service Company of New Hampshire ("PSNH") the pricing terms of the power purchase agreements associated with 13 small hydroelectric generating facilities in New Hampshire. Subject to certain approvals and adjustments, as consideration for a reduction in the above-market rates stipulated in these power purchase agreements, the Fund is expected to receive approximately $30,600 (U.S. $20,400) after the first quarter. After completion of these transactions, PSNH will continue to purchase the energy produced by these generating stations at the New England power pool market price.

Trustees

Algonquin Power Management Inc.

Chris K. Jarratt, *Director and Chief Executive Officer*

John M.H. Huxley, *Director*

Ian E. Robertson, *Director*

David C. Kerr, *Director*

Peter Kampian, *Chief Financial Officer*

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Toronto, Ontario M5H 4A6

Annual General Meeting

Thursday, June 26, 2003
Blake, Cassels & Graydon LLP
23rd Floor, 199 Bay Street
Toronto, Ontario

Stock Exchange

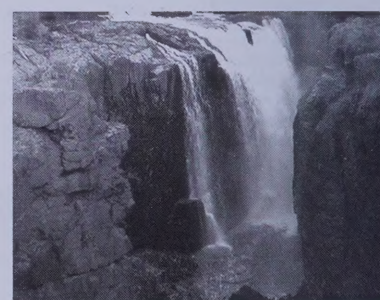
The Toronto Stock Exchange Symbol:
APF.UN

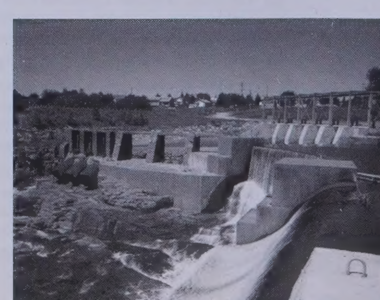
Auditors

KPMG LLP, Toronto, Ontario

Legal Counsel

Blake, Cassels & Graydon LLP, Toronto, Ontario





Alternative Fuels

Brooklyn, Nova Scotia • Joliet, Illinois • Chapais, Québec • Drayton Valley, Alberta • KMS Peel, Ontario

Cogeneration

Cardinal, Ontario • Cochrane, Ontario • Kirkland Lake, Ontario • Crossroads, New Jersey • Sanger, California

Hydroelectric

Adams, New York • Arthurville, Québec • Ashuelot, New England • Avery, New England • Belleterre, Québec • Burgess Dam, Ontario Burt Dam, New York • Campbellford, Ontario • Christine Falls, New York • ChuteFord, Québec • Clement Dam, New England • Cranberry Lake, New York Dickson Dam, Alberta • Donnacona, Québec • Drag Lake, Ontario • Forestport, New York • Franklin, New England • Great Falls, New Jersey Gregg Falls, New England • Hadley, New England • Herkimer, New York • Hollow Dam, New York • Hopkinton, New England • Hurdman Dam, Ontario Kayuta Lake, New York • Kings Falls, New York • Lakeport, New England • Lochmere, New England • Long Sault Rapids, Ontario • Lower Robertson, New England Milton, New England • Mine Falls, New England • Moretown, New England • Mont-Laurier, Québec • Odgensburg, New York • Otter Creek, New York Pembroke, New England • Phoenix, New York • Rattle Brook, Newfoundland • Rawdon, Québec • Rivière-du-Loup, Québec • Saint-Alban, Québec Ste-Brigitte, Québec • Ste-Catherine, Québec • St-Hyacinthe, Québec • St-Raphaël, Québec • Worcester, New England

Infrastructure

Bella Vista, Arizona • Black Mountain, Arizona • Gold Canyon, Arizona • Tall Timbers, Texas • Woodmark, Texas

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